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2005

ANNUAL REPORT

PETRO-REEF RESOURCES LTD.

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PETRO-REEF RESOURCES LTD.

MANAGEMENT'S DISCUSSION AND ANALYSIS

FORM 51-102F1

ANNUAL REPORT 2005

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MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis for Petro-Reef Resources Ltd. should be read in conjunction with the audited financial statements and notes, contained in the annual report for 2005 and are based on information available to April 2006. Additional information regarding Petro-Reef is available in the updated Annual Information Form which has been filed electronically, at the same time as this report, on the System for Electronic Document Analysis and Retrieval (SEDAR) at www.sedar.com or on Petro-Reef's website at www.petro-reef.ca.

ABBREVIATIONS

ARTC	Alberta Royalty Tax Credit	Mbbls	thousands of barrels
Bbl	barrel	Mcf	thousand cubic feet
Bbls	barrels	Mcf/d	thousand cubic feet per day
Bcf	billion cubic feet	MMbbls	millions of barrels
BOE	barrel of oil equivalent (1 BOE = 6 Mcf)	MMcf	million cubic feet
		MMcf/d	million cubic feet per day
Bo/d	Barrels of oil per day	FNR	future net revenue
GJ	Gigajoule	NGL	natural gas liquids
GJs/d	Gigajoules per day	NPV	net present value

NOTE: In this report all currency values are in Canadian Dollars.

FORWARD-LOOKING STATEMENTS

Some of the statements contained herein (including without limitation, financial and business prospects and financial outlooks) may be forward-looking statements which reflect management's expectations regarding future plans and intentions, growth, results of operations, performance and business prospects and opportunities. Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue" and similar expressions have been used to identify these forward-looking statements. These statements reflect management's current beliefs and are based on information currently available to management. Forward-looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements including, but not limited to, changes in general economic and market conditions and other risk factors. Although the forward-looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward-looking statements. Investors should not place undue reliance on forward-looking statements. These forward-looking statements are made as of the date hereof and the Corporation assumes no obligation to update or review them to reflect new events or circumstances.

Forward-looking statements and other information contained herein concerning the oil and gas industry and the Corporation's general expectations concerning this industry is based on estimates prepared by management using data from publicly available industry sources as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which the Corporation believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While the Corporation is not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on various factors.

NOTE:

Petro-Reef cautions that “cash flow from operations” and “netbacks” do not have standardized meanings prescribed by Canadian generally accepted accounting principles and are therefore unlikely to be comparable to similar measures presented by other issuers. Management believes “cash flow from operations,” defined as cash provided by operations before changes in non-cash working capital, is a useful indicator of the Company’s ability to fund future capital expenditures, Petro-Reef calculates netbacks as net dollars per barrel after Crown Royalties, operating expenses and general and administrative expenses.

Reference is made to barrels of oil equivalent (BOE). Barrels of oil equivalent may be misleading, particularly if used in isolation. In accordance with National Instrument 51-101, a BOE conversion ratio for natural gas of 6 Mcf: 1 Bbl has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency a the wellhead.

PETRO-REEF RESOURCES LTD.
CORPORATE INFORMATION

DIRECTORS AND OFFICERS

Joseph Werner[4]
Chief Executive Officer
President & Director
Calgary, Alberta

Theodore M. Donhuysen[3] [4] [5]
Vice-President Exploration & Production
Chief Operating Officer & Director
Calgary, Alberta

Alan P. Hallman[2] [3]
Director
Calgary, Alberta

Dennis K. Ulrich
Director
Medicine Hat, Alberta

Jack P. Donhuysen[2] [5]
Director
Calgary, Alberta

Huba A. Sebo[1] [5]
Director
Calgary, Alberta

N. Gary Van Nest[1][3]
Director
Calgary, Alberta

Richard W. DeVries[1][2]
Director
Freeport, The Bahamas

Robert N. Maertens-Poole
Chief Financial Officer
Calgary, Alberta

Gary W. Coleman
Assistant Secretary
Calgary, Alberta

R. Greg Powers[6]
Corporate Secretary
Legal Counsel
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Stock Listing
TSX Venture Exchange
Trading Symbol: **PER**

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PricewaterhouseCoopers LLP
Chartered Accountants
3100, 111 - 5th Avenue S.W.
Calgary, Alberta T2P 5L3

Bank
National Bank of Canada
301 – 6th Avenue S.W.
Calgary, Alberta T2P 4M9

Registrar and Transfer Agent
CIBC Mellon Trust Company
600, 333 - 7th Avenue S.W.
Calgary, Alberta T2P 2Z1

Investor Relations
Iradesso Communications Corp.
400, 805 – 10th Avenue S.W.
Calgary, Alberta T2R 0B4

(1) Member of the Audit Committee
(2) Member of the Compensation Committee
(3) Member of the Corporate Governance Committee
(4) Member of the Management Committee
(5) Member of the Reserves Committee
(6) Baker & McKenzie
2600, 255 - 5th Avenue S.W.
Calgary, Alberta T2P 3G6

THE YEAR 2005 IN REVIEW

Petro-Reef Resources Ltd. (TSX-V: PER), a Calgary based crude oil and natural gas exploration and production company with producing properties in Alberta, Canada, capitalized on its drilling success and strong commodity prices to earn $248,714 on cash flow from operations of $2,187,030 in 2005. This compares to a loss of $542,087 on cash flow from operations of $1,514,596 in 2004. The Company exited 2005 producing 706 barrels of oil equivalent per day compared to an exit rate of 238 BOE/d.

Total production for 2005 was 66,305 barrels of oil equivalent (BOE), an increase of five percent over the production for 2004 of 62,936 BOE.

Petro-Reef's production in 2005 came from two core properties, Alexander/Qui Barre and Peavey/Morinville, both located near Edmonton, Alberta. Alexander/Qui Barre produced about 83 percent of total production for about 81 percent of the revenue while, Peavey/Morinville, produced about 16 percent of total production for about 18 percent of the revenue. The remaining production came from minor working interest and royalty properties. About 99.9 percent of the production was natural gas with about 0.1 percent as crude oil and natural gas liquids.

Activities during the year included drilling, completions, tie-ins, and work-overs/re-completions. Additional 2-D and 3-D seismic data were acquired, processed and interpreted.

The company continues to use the following exploration criteria on each prospect to assure high profitability and rate of return on capital investment:

1) Each exploration prospect must exhibit
    a) Potential for a minimum of three hydrocarbon zones.
    b) Potential for:

        (i) 10:1 profit to capital risk ratio
        (ii) a minimum of 30 percent rate of return on capital invested
        (iii) minimum life of 15 years

2) Both 2-D and 3-D seismic are used to identify and confirm potential drilling locations using state-of-the-art technology.

Management uses cash flow from operations per share to analyze operating performance. Cash flow from operations per share does not have any standardized meaning prescribed by Canadian Generally Accepted Accounting Principles ("GAAP") and therefore it may not be comparable with the calculation of similar measures for other entities.

PETRO-REEF RESOURCES LTD.

Highlights of Financial and Operations Results for Fiscal Years 2005 and 2004.

Financial	Year Ended December 31, 2005	Year Ended December 31, 2004	% Change
Crude oil and Natural Gas Revenue	$3,224,567	$2,162,656	+49
Cash flow from operations	$2,187,030	$1,514,596	+45
Net earnings (loss) from operations	$248,714	($542,087)	-
Net earnings (loss) per share	$0.01	($0.03)	-
Capital Expenditures	$2,374,843	$1,148,725	+107
Bank Balance (Loan)	$397,904	($700,000)	-
Shareholder's equity	$6,029,968	$4,021,269	+50
Common shares outstanding Weighted average	18,994,641	17,701,232	+7
Operations	**Year Ended December 31, 2005**	**Year Ended December 31, 2004**	**% Change**
Daily Average Production			
Crude Oil and NGLs (Bbls/day)	2	13	-85
Natural Gas (mcf/day)	1,080	954	+13
Total BOE/day	182	172	+6
Average Selling Price			
Crude Oil ($per Bbl)	57.97	45.25	+28
Natural Gas ($per mcf)	9.57	6.51	+47
NGL ($per Bbl)	55.50	48.25	+15
Operations	**December 2005**	**December 2004**	**% Change**
Daily Average Production			
Crude Oil and NGLs (Bbls/day)	1	0	-
Natural Gas (mcf/day)	2,731	1,437	+90
Total BOE/day	456	240	+90
Average Selling Price			
Crude Oil ($/Bbl)	44.70	-	-
NGL ($/Bbl)	-	-	-
Natural Gas ($/mcf)	12.86	6.38	+102

THREE-YEAR REVIEW

	2005	2004	2003
FINANCIAL			**(Restated)**
Crude Oil and Natural Gas Revenue Net of royalties and ARTC	$3,224,567	$2,162,656	$894,261
Net (Loss) Earnings from Operations	$248,714	($542,087)	($156,741)
Net (Loss) Earnings per Share	$0.01	($0.03)	($0.01)
Capital Expenditures	$2,374,843	$1,148,725	$1,557,439
Total Assets	$10,462,289	$8,691,850	$8,174,724
Bank Balance (Loan)	$397,904	($700,000)	($1,150,000)
Shareholder's Equity	$6,029,968	$4,021,268	$4,247,706
Common Shares Outstanding			
End of Period	21,438,924	17,738,937	17,688,937
Weighted Average	18,994,641	17,701,232	17,688,937
OPERATIONS			
Average Production			
Crude Oil and NGLs (Bbls/day)	2	13	6
Natural Gas (Mcf/day)	1,080	954	409
Total BOE per day 6:1	182	172	74
Finding & Development Cost per BOE [1]	$5.27	$9.61	$18.00
Netbacks ($ per BOE) [3]	$34.90	$23.70	$23.95
Reserve Replacement Ratio	2.41	0.66	3.2
Average Selling Price			
Crude Oil ($ per BOE)	59.97	$45.25	$43.21
Natural Gas ($ per BOE)	57.43	$37.02	$39.96
NGL ($ per BOE)	55.50	$48.25	$44.14
Reserves (Proved plus Probable)			
Crude Oil and NGLs (Bbls)	1,000	16,300	40,400
Natural Gas (MMcf)	3,754	2,569	2,527
Total BOE	503,500	444,467	461,600
Present Value of Reserves (M$) [2]			
Undiscounted before Taxes	$26,119	$12,848	$13,277
Discounted before Taxes at 10%	$18,639	$9,294	$9,490
Established Reserve Life Index (P+P)	22.5 yrs	32.6 yrs	24.4 yrs
Proved Reserve Life Index	19.3 yrs	18.3 yrs	15.4 yrs

(1) After revisions due to NI51-101.
(2) Using constant prices and costs.
(3) Using a conversion of 6,000 cubic feet of natural gas for one barrel of oil equivalent.
(4) Crude oil sales were non-operated and reported with total oil and gas sales combined.

Netbacks are calculated by subtracting royalty expenses and operating expenses from revenue per barrel of oil equivalent. These calculations are before Alberta Royalty Tax Credits.

Petro-Reef's reserve replacement ratio for 2005 using proved reserves only was 2.41 to 1. Reserve replacement ratio for a given year is calculated by dividing total reserves at the end of the year by the total reserves at the beginning of the year.

Operating costs for 2005 averaged about $63,000 per month, an increase from an average of about $51,000 per month for 2004. The increased costs were a result of costs of fieldwork required to produce the one new well drilled in June 2005 and the re-completion, and reworking of more wells than in 2004. In December 2005 operating costs almost doubled the average for the year with the onset of production of the latest natural gas well at a rate in excess of four million cubic feet per day (MMcf/d), for a 90 percent increase in production.

Net general and administration costs had a modest increase to approximately $34,500 per month in 2005 from approximately $33,000 per month in 2004 and approximately $28,600 per month in 2003. Except for some minor increases, the highest costs since 2003 were due to additional reporting requirements, legal, accounting, engineering and related third party charges.

Capital expenditures for 2005 were $2,378,843 compared with $1,148,725 in 2004, an increase of 107 percent.

The net present value of proved plus probable reserves at constant prices and costs (undiscounted), before income tax, for 2005 is $26,119,000. This is a 107 percent increase from $12,634,000 in 2004. The comparable numbers at a 10 percent discount of future net revenues are $18,639,000 for 2005, and $9,094,000 for 2004, a 105 percent increase.

There are no long-term financial liabilities and there have been no dividends declared.

At year end there was no bank loan.

Revenues fluctuated during 2005 because of changes in volumes of product produced and with changes in product price. Because Petro-Reef produces more than 99 percent natural gas, natural gas prices fluctuations had more impact than prices for crude oil. The following table shows natural gas prices received by Petro-Reef for 2005, 2004 and 2003 by month and by quarter.

Product Price for Natural Gas ($ per Gigajoule)
Years: 2005-2004-2003

Month of:	$ Price Per GJ Year 2005	$ Price Per GJ Year 2004	$ Price Per GJ Year 2003
January	6.233800	6.659749	6.643443
February	6.260490	5.757239	8.516847
March	7.000700	5.881507	8.081131
Average Price per Quarter:	6.498330	6.099498	7.747140

April	7.347800	6.274938	6.432713
May	6.562240	6.950898	6.497444
June	7.052828	6.564088	6.272281
Average Price per Quarter:	6.987623	6.596645	6.400812

July	7.058280	6.479279	5.478141
August	8.727350	5.724071	5.700614
September	10.478270	5.326431	5.328396
Average Price per Quarter:	8.754633	5.843260	5.502383

October	11.725960	6.170750	5.245812
November	8.837250	5.878970	4.989099
December	11.414247	6.382450	6.178671
Average Price per Quarter:	10.659152	6.1440570	5.471194

Average Price for Year	8.22	6.17	6.28

Note: 1 gigajoule = 1.054615 thousand cubic feet

SELECTED FINANCIAL INFORMATION

FINANCIAL (year-ended December 31)	2005	2004	2003
Crude Oil and Natural Gas Revenue net of royalties and ARTC	$3,224,567	$2,162,656	$894,261
Cash Flow from Operations	$2,187,030	$1,514,596	$17,029
Net (Loss) Earnings from Operations	$248,714	($542,087)	($156,741)
Net (Loss) Earnings per Share, Basic and Diluted	$0.01	($0.03)	($0.01)
Capital Expenditures	$2,374,843	$1,148,725	$1,557,439
Total Assets	$10,462,289	$8,691,850	$8,174,724
Bank Balance (Loan)	$397,904	($700,000)	($1,150,000)
Shareholders' Equity	$6,029,968	$4,021,269	$4,247,706

The following table summarizes the results of the 12 most recently completed quarters.

Summary of Quarterly Results For The Last Twelve Quarters				
		Oil & Gas Sales Net of Royalties And ARTC	Net Earnings (Loss)	Basic and Diluted Earnings per share
2003			(Restated)	
	Q1	$211,493	($609)	$0.00
	Q2	$176,756	$14,964	$0.00
	Q3	$119,614	($113,592)	$0.00
	Q4	$386,398	($57,504)	($0.01)
Total		$894,261	($156,741)	
2004				
	Q1	$354,288	($81,806)	$0.00
	Q2	$531,591	($75,371)	$0.00
	Q3	$499,139	$34,086	$0.00
	Q4	$777,638	($418,996)	($0.03)
Total		$2,162,656	($542,087)	
2005				
	Q1	$743,193.70	($14,869)	$0.00
	Q2	$522,696.91	($24,224)	$0.00
	Q3	$560,987.35	($21,890)	$0.00
	Q4	$1,201,738.84	$309,697	$0.01
Total		$3,224,577.67	$248,714	

The following tables summarize the production and revenues for 2003-2004-2005.

2003 PRODUCTION AND REVENUE SUMMARY BY PRODUCTION DATE

	(1) BOE	(2) BOE / Day	(3) REVENUE $	(4) ROYALTIES $	(5) EXPENSES $	(6) (3)-(4)-(5) $	(7) NET BACK $ / BOE	(8) NET G + A $	(9) (6) – (8) $
JAN	1,446.67	46.67	61,120.33	8,415.35	14,010.20	38,694.78	26.75	25,181.45	13,513.33
FEB	1,628.14	58.15	86,808.34	12,609.41	16,382.34	57,816.59	35.51	15,181.43	42,635.16
MAR	1,965.54	63.40	97,834.87	13,850.14	17,076.10	66,908.63	34.04	41,641.91	25,266.72
APR	1,582.68	52.76	64,149.81	9,153.37	19,390.41	35,606.03	22.50	34,567.39	1,038.64
MAY	1,353.92	43.67	54,501.52	6,135.92	18,498.43	29,867.17	22.06	37,283.69	(7,416.52)
JUN	1,325.16	44.17	52,885.88	7,056.38	26,555.96	19,273.54	14.54	32,785.47	(13,511.93)
JUL	1,394.02	44.97	49,595.53	6,214.66	18,414.23	24,966.64	17.91	29,866.18	(4,899.54)
AUG	2,080.81	67.12	74,596.15	8,995.62	17,078.82	48,521.71	23.32	28,189.32	20,332.39
SEP	1,961.11	65.37	65,408.29	8,414.63	21,944.48	35,049.18	17.87	23,415.38	11,633.80
OCT	2,316.69	74.73	76,024.03	10,194.01	15,562.02	50,268.00	21.70	12,933.00	37,335.00
NOV	4,110.79	137.03	130,065.50	12,442.85	36,976.18	80,646.47	19.62	19,667.21	60,979.26
DEC	6,055.15	195.33	236,099.75	35,432.90	36,971.05	163,695.80	27.03	42,943.81	120,751.99
ARTC			1,049,090.00 7,155.00			651,314.54 7,155.00			307,658.30 7,155.00
Total	27,220.66	893.37	1,056,245.00	138,915.24	258,860.22	658,469.54	282.85	343,656.24	314,813.30
Average	2,268.39	74.45	88,020.42	11,576.27	21,571.69	54,872.46	23.93	28,638.02	26,234.44

NOTES:

(3) Product sales and royalty income
(6) Net revenue after royalties and operating expenses
(9) Net profit before bank debt
ARTC – Alberta Royalty Tax Credit

2004 PRODUCTION AND REVENUE SUMMARY BY PRODUCTION DATE

	(1) BOE	(2) BOE / Day	(3) REVENUE $	(4) ROYALTIES $	(5) EXPENSES $	(6) (3)-(4)-(5) $	(7) NET BACK $ / BOE	(8) NET G + A $	(9) (6) – (8) $
JAN	2,825.17	91.13	137,355.77	12,709.29	43,284.05	81,362.43	28.80	18,837.22	62,525.21
FEB	3,641.01	125.55	133,496.03	13,771.13	42,704.64	77,020.29	21.15	29,074.94	47,945.35
MAR	3,417.61	110.25	127,525.48	14,289.24	48,280.94	64,955.30	19.01	15,259.65	49,695.65
APR	5,770.79	192.36	233,092.98	15,498.94	61,999.80	155,594.24	29.96	45,816.05	109,778.19
MAY	3,992.75	128.80	180,722.54	15,395.47	43,759.92	121,567.15	30.45	16,384.28	105,182.87
JUN	3,466.69	115.56	145,289.96	13,848.70	48,927.05	82,514.21	23.80	39,837.73	42,676.48
JUL	3,715.14	119.84	152,414.21	13,674.49	37,332.76	101,406.96	27.30	35,132.52	66,274.44
AUG	3,905.77	125.99	149,652.72	23,671.87	80,493.17	45,487.68	11.65	12,289.45	33,198.23
SEP	8,257.77	275.26	281,082.07	62,951.32	58,432.77	159,647.98	19.33	25,906.62	133,741.36
OCT	8,447.87	272.51	342,544.17	71,917.97	55,010.69	215,615.51	25.52	25,410.16	190,205.35
NOV	8,070.05	269.00	320,631.26	85,299.54	52,887.68	182,444.04	22.61	24,348.22	158,095.82
DEC	7,425.08	239.52	318,982.17	91,470.06	43,000.63	184,511.48	24.85	108,273.16	76,238.32
ARTC			2,523,789.39 76,388.00			1,472,127.27 76,388.00			1,075.557.27 76,388.00
Total	62,935.71	2,065.77	2,600,177.39	434,498.02	616,164.70	1,548,515.27	284.43	396,570.00	1,151,945.27
Average	5,244.64	172.15	216,681.45	36,208.17	51,347.06	129,042.94	23.70	33,047.50	95,995.44

NOTES:

(3) Product sales and royalty income
(6) Net revenue after royalties and operating expenses
(9) Net profit before bank debt
ARTC – Alberta Royalty Tax Credit

2005 PRODUCTION AND REVENUE SUMMARY BY PRODUCTION DATE WITHIN ACCOUNTING

	(1) BOE	BOE / Day	(3) REVENUE $	(4) ROYALTIES $	(5) EXPENSES $	(6) (3)-(4)-(5) $	(7) NET BACK $ / BOE	(8) NET G + A $	(9) (6) – (8) $
JAN	7,367.51	237.66	310,711.42	70,680.79	64,643.59	175,387.04	23.81	22,325.27	153,061.77
FEB	6,773.74	241.92	288,734.03	60,640.03	59,529.17	168,564.83	24.89	22,844.63	145,720.20
MAR	7,191.67	231.99	343,926.08	68,857.01	60,307.95	214,761.12	29.86	19,485.05	195,276.07
APR	5,609.23	186.97	283,212.95	59,962,41	54,385.15	168,865.39	30.10	10,822.37	158,043.02
MAY	4,970.16	160.33	222,242.41	44,181.74	38,870.44	139,190.23	28.01	20,272.25	118,917.98
JUNE	2,986.45	99.55	140,777.82	19,392.12	75,196.28	46,189.42	15.47	15,554.30	30,635.12
JUL	3,095.79	99.86	179,998.70	31,696,59	62,789.33	85,512.78	27.62	87,883.82	(2,371.04)
AUG	3,901.35	125.85	229,811.06	37,950.26	59,278.69	132,582.11	33.98	32,723.56	99,858.55
SEP	3,825.79	127.53	266,590.43	45,765.99	63,607.76	157,216.68	41.09	31,017.72	126,198.96
OCT	3,107.61	100.25	245,614.59	40,079.51	49,190.15	156,344.93	50.31	10,397.90	145,947.03
NOV	3,418.72	113.96	202,850.89	39,535.41	46,393.77	116,921.71	34.20	28,003.25	88,918.46
DEC	14,141.01	456.16	1,086,446.35	253,558.07	119,574.69	713,313.59	50.44	112,837.66	600,475.93
Total	66,389.03	181.84 [1]	3,800,916.73	772,299.93	753,766.97	2,274,849.83	34.27 [3]	414,167.78	1,860,682.05
Other Months	(84.00)	(0.23)[1]	(2,644.73)	(45,699.28)	3,936.03	39,118.52	0.63	-	-
Total	66,305.03	-	3,798,272.00	726,600.65	757,703.00	2,313,968.35	-	-	-
ARTC	-	-	152,896.00	-	-	152,896.00	-	-	152,896.00
Total	-	-	3,951,168.00	-	-	2,466,864.35	-	-	2,013,578.05
Average	5,525.42	181.61	329,264.00	60,550.05	63,141.92	205,572.03	34.90	34,513.98	167,798.17

Column (3) Product sales and royalty income
Column (6) Net revenue after royalties and operating expenses
Column (9) Net profit before bank debt
[1] Average

PROPERTY REVIEW

Petro-Reef operated the drilling of two wells in the Alexander/Qui Barre, Alberta area in 2005. The company drilled the first well in May 2005. This well was drilled directionally in order to penetrate Lower Cretaceous zones at the desired location. Natural gas was encountered in several up-hole formations which required the use of progressively heavier drilling fluid to control the natural gas and prevent a potentially dangerous blow-out situation. The well was drilled to total depth and was being prepared to run logs when the drill pipe became permanently stuck, even after several days of attempting to break it free. The drill pipe was cut off above the portion that was stuck and cemented in place. It was still possible to complete a drill stem test in the Belly River formation up-hole. The test produced natural gas with inconclusive results. Petro-Reef plans to drill a new well from the same surface location. From the information obtained from the directional hole it has been concluded that a vertical hole should encounter the prospective lower zones in a more favorable position. This decision is based on further geological and geophysical evaluation of all available data.

Petro-Reef drilled its second well of 2005 in October and reported the results in a news release on October 27, 2005 as follows:

> Petro-Reef Resources Ltd. ("the company") drilled a well in its core area at Alexander, Alberta in October 2005. The well was completed with production casing run and absolute open flow tested at 335.549 e^3m^3/day (11.910 MMcf/d) or 1,985 barrels of oil equivalent per day.
>
> The well will be placed on stream at approximately 3.25 MMcf/d (542 BOE/d – 461 BOE/d net to Petro-Reef before BTU adjustment). The company has an 85 percent working interest in the well until 500 percent of the drilling and completion cost and 200 percent of the equipping and tie-in cost have been recovered at which time Petro-Reef's working interest will revert to 34 percent.

This well was put into production at a rate in excess of 4 MMcf/d and has maintained this level to date.

On November 9, 2005 Petro-Reef issued another news release regarding activities in the area as follows:

> Petro-Reef Resources Ltd. announces that it has successfully recompleted a well in its core area at Alexander, Alberta. The well based on a one-day production test, tested at a rate of 300 barrels of 24° API crude oil per day. The company has a 44 percent working interest in the well and is the operator. The well will be placed on stream at an anticipated production rate of 150 barrels of crude oil per day (66 barrels of crude oil per day net to Petro-Reef).
>
> The company has three other wells structurally higher with the same oil zone defined on well logs. The company owned 3-D seismic indicates the oil reservoir to be potentially 3.5 miles long and 1.0 to 1.5 miles wide with pay thickness ranging from 30 to 60 feet.

An attempted completion of this well was unsuccessful. Further evaluation continues for this well for eventual recompletion in another zone.

Plans for the Alexander/Qui Barre area are to drill additional wells, both development and exploration. The approximately eight square miles of 3-D seismic acquired in 2003 and the 3-D seismic of approximately six square miles acquired in 2005 have been interpreted and indicate at least 25 potential drilling locations for oil and or natural gas. These locations will be used to validate much of the acreage in the area. With success these wells will lead to further development and other exploration drilling.

In the Peavey/Morinville, Alberta prospect area no new wells were drilled in 2005. The emphasis in 2004 and 2005 was to develop production from several capped natural gas wells that either had not been tied-in for production or were candidates for re-completion in up-hole horizons because they had previously tested or indicated by log analysis that they were capable of commercial production.

Spring break-up 2005 took an unusually long time followed by extended rain. The combination caused serious shutdown periods during which it was not possible to service the wells when there were problems. Mother Nature dealt Petro-Reef another challenge when lightning struck an oil tank, blew off the top and burned the contents. The area was promptly cleaned up, the tank was replaced, and production resumed in short order.

SUBSEQUENT EVENTS

On January 9, 2006 Petro-Reef updated shareholders on the corporation's progress as follows:

> Petro-Reef exited 2005 producing in excess of 1,050 BOE/d gross, 700 BOE/d, net to Petro-Reef up from its forecast of 650 BOE/d. The increase in production is primarily due to its position in the recently announced successful gas well going on stream in its core area at Alexander, Alberta. The company has an 85 percent working interest in the well until 400 percent of the drilling and completion cost and 200 percent of the equipping and tie-in cost have been recovered at which time Petro-Reef's working interest will revert to 34 percent.
>
> Petro Reef reports also, that it will be participating in drilling four new offsetting wells and recompleting three wells. This is expected to take place in the first quarter of 2006. These seven wells will be drilled and recompleted in the core area of Alexander, Alberta. The industry demand for drilling rigs and service rigs is very strong. Timely availability of rigs may become a problem. Petro-Reef has working interest in these wells ranging from thirty-four percent to forty-four percent.
>
> For 2006 Petro-Reef plans to drill/recomplete up to 30 wells using cash flow and the existing line of bank credit.

This was followed on March 20, 2006 by the following news release:

> Petro-Reef Resources Ltd., a junior oil and gas company operating in Alberta, is pleased to announce that it has secured two drilling rigs to resume its drilling program in its core area of Alexander, Alberta. Petro-Reef has been unable to pursue its program since November 2005 due to industry-wide challenges with rig availability. Because the Company anticipated rig availability issues, the resumed drilling program puts Petro-Reef back on track to achieve its production targets.
>
> As part of the renewed program, Petro-Reef plans to drill five more wells offsetting a successful natural gas discovery in October 2005. In October, the Company announced that it had completed a new natural gas well at 12-28 in its core area of Alexander/Qui Barre. The well tested at 11.91 million cubic feet per day (MMcf/d), equivalent to 1,958 barrels of oil equivalent per day (BOE/d). The well was placed on production in December 2005 and has been producing at a stabilized rate of 4.18 MMcf/d (697 BOE/d). Petro-Reef's interest in the well is 84 percent before payout of a 400 percent penalty.

As a result of the success of the 12-28 well drilled in October 2005, Petro-Reef has increased its interest in the Alexander/Qui Barre area by 20 percent, taking its interest in an additional fifteen (15) wells to a range of between 54 percent and 64 percent on 9,271 gross acres (4,966 net acres) for an average of 51 percent.

A second well drilled as part of the program in November 2005 was anticipated to produce at 66 Bop/d net. This well has since been suspended due to water production. Petro-Reef has a 44 percent interest in the well. Early production from the well was not included in Petro-Reef's 2005 forecasts.

As previously announced, Petro-Reef expects to drill or recomplete up to 25 wells in 2006 rig availability permitting. The Company is currently producing between 600 and 700 BOE/d. Petro-Reef is on track to exit 2006 producing between 1,100 BOE/d and 1,500 BOE/d.

The results of operations in 2005, 2004 and 2003 are set out in the following tables under three categories:

1) Land acquisitions
2) Petro-Reef operated wells
3) Wells where Petro-Reef is not the operator

Joint-venture partnerships are involved in both the operated and non-operated drilling and accounts for the varying interests held by Petro-Reef.

LAND COSTS FOR THE ACQUISITION OF MINERAL LEASES
(NET OF DISPOSITIONS, RENTALS OR SURFACE LEASES)

YEAR	PERIOD	GROSS ACRES	NET ACRES	COST (NET)	COMMENTS
2003	Q1	0	0	$ 287	Lease Service Only
	Q2	160	70	$ 4,677	
	Q3	480	212	$26,593	
	Q4	640	282	$26,594	
TOTAL		**1280**	**564**	**$58,151**	$103 average per net acre
2004	Q1	6	3	$ 480	Lease Service Only
	Q2	-	-	$ 466	
	Q3	1,189	404	$16,140	
	Q4	1,829	724	$61,506	
TOTAL		**3,024**	**1,113**	**$78,592**	$71 average per net acre
2005	Q1	1,920	653	$103,316	
	Q2	480	206	$ 32,500	
	Q3	1,920	960	$ 51,837	
	Q4	968	752	$ 35,232	
TOTAL		**5,288**	**2,571**	**$222,885.58**	$87 average per net acre

Lease Service Only cost refers to third party land company expenses.

The increases for 2004 and 2005 are 97 percent and one 103 percent for acreage, and 35 percent and 183 percent for costs respectively.

PETRO-REEF RESOURCES LTD. OPERATED WELLS

DRILLING, COMPLETION & WORKOVERS			
YEAR	**LOCATION**	**COST**	**PER % W.I.**
2003			
Q1			
Q2			
Q3	05-31-55-26W4	$460,710	44.00
Q4			
Q1	14-30-55-26W4	$722	24.00
2004			
Q2	14-30-55-26W4	$147,450	24.00
	05-31-55-26W4	$21,093	44.00
Q3	14-30-55-26W4	$23,319	24.00
	05-31-55-26W4	$17,741	44.00
	09-30-56-24W4	$4,755	71.50
	05-25-56-25W4	$192	39.00
Q4	14-30-55-26W4	$1,757	24.00
	05-31-55-26W4	$219	44.00
	05-25-56-25W4	$18,612	39.00
2005			
Q1	10-30-56-27W4	$17,284	35.13
	13-29-55-26W4	$2,746	44.00
	05-31-55-26W4	$1,641	44.00
	06-15-56-27W4	$152	50.00
	14-25-55-25W4	$13	15.96
	16-26-55-25W4	$274	50.00
	16-26-56-25W4	$332	25.88
	04-19-56-24W4	$26,689	36.50
	06-35-56-25W4	$639	61.28
	07-32-56-25W4	$2,083	72.50
	07-35-56-25W4	$440	62.27
	05-25-56-25W4	$166	39.00
Q2	10-30-56-27W4	$1,253	35.13
	13-29-55-26W4	$193,660	44.00
	14-30-55-26W4	$5,411	24.00
	05-31-55-26W4	$31,294	44.00
	14-25-55-25W4	$431	15.96
	16-26-55-25W4	$329	50.00
	05-36-55-25W4	$308	20.00
	06-35-56-24W4	$3,333	61.28
	07-32-56-25W4	$144	72.50
	07-35-56-25W4	$63	62.27

DRILLING, COMPLETION & WORKOVERS cont.			
YEAR	**LOCATION**	**COST**	**PER % W.I.**
2005			
Q3	12-28-55-26W4	$68,506	54.00
	13-29-55-26W4	$34,348	44.00
	05-31-55-26W4	$61,285	44.00
	06-01-56-27W4	$7,297	44.00
	06-15-56-27W4	$1,136	50.00
	14-25-55-25W4	$59	15.96
	16-26-55-25W4	$53	50.00
	04-19-56-24W4	$383	36.50
	05-36-55-25W4	$965	20.00
	06-35-56-25W4	$2,183	62.27
	07-32-56-25W4	$429	72.50
	07-35-56-25W4	$501	62.27
Q4	10-33-55-26W4	$13,025	54.00
	11-27-55-26W4	$3,918	54.00
	12-28-55-26W4	$488,346	54.00
	12-33-55-26W4	$5,693	54.00
	13-21-55-26W4	$4,271	54.00
	13-29-55-26W4	$927	44.00
	05-31-55-26W4	$6,362	44.00
	06-01-56-27W4	$4,303	44.00
	08-01-56-27W4	$128,790	44.00
	05-36-55-25W4	$557	20.00
	06-35-56-25W4	$1,105	61.28
	07-35-56-25W4	$558	62.27
	05-25-56-25W4	$25,852	39.00

Note (1) Reserves as determined by independent engineering appraisal at the end of each year that the well is drilled in (proved reserves only)

PETRO-REEF RESOURCES LTD. OPERATED WELLS

EQUIPPING & TIE-IN								
YEAR	**LOCATION**	**COST**	**PER % W.I.**	**PER % GORR**	**First Month Production BOE/D**	**First Month Revenue (Net PER)**	**Revenue December (Net PER)**	**Reserves (1) (Net PER)**
2003								
Q1								
Q2								
Q3								
Q4	05-31-55-26W4	$176,761	44.00		134.00	$131,109	$131,109	Being Evaluated
2004								
Q1	10-30-56-27W4	$22,260	35.13					
	05-31-55-26W4	$93,669	44.00					
	09-30-56-24W4	$39,216	71.50	0.855	424.74	$16,982	$161,110	575
Q2	05-31-55-26W4	$34,438	44.00					
	09-30-56-24W4	$35,710	71.50	0.855				
Q3	14-30-55-26W4	$57,570	34.00		1,660.22	$36,725	$659,674	229
	05-31-55-26W4	$4,444	44.00					
	09-30-56-24W4	$231	71.50	0.855				
Q4	14-30-55-26W4	$278	34.00					
	05-31-55-26W4	($61)	44.00	0.33				
2005								
Q1	14-30-55-26W4	$3,333	24.00					
	05-31-55-26W4	$35,216	44.00					
	04-19-56-24W4	$68,343	36.50					
	05-25-56-25W4	$63,341	39.00					
	09-30-56-24W4	$7,299	71.50					
Q2	10-30-56-27W4	$5,109	35.13					
	13-29-55-26W4	$3,105	34.00					
	14-30-55-26W4	$278	24.00					
	04-19-56-24W4	$221	36.50					
	09-30-56-24W4	$11,895	71.50					
Q3	13-29-55-26W4	$2,112	44.00					
	14-30-55-26W4	$88	44.00					
Q4	12-28-55-26W4	$345,486	54.00					
	14-30-55-26W4	$22,355	24.00					
	05-31-55-26W4	$5,333	64.00					
	06-01-56-27W4	$134	44.00					
	08-01-56-27W4	$97,678	44.00					
	05-25-56-25W4	($11,032)	39.00					
	09-30-56-24W4	$18,389	71.50					

Note (1) Reserves as determined by independent engineering appraisal at the end of each year in which the well was drilled (proved reserves only).

PETRO-REEF RESOURCES LTD. NON-OPERATED WELLS

DRILLING, COMPLETION & WORKOVERS									
Year	**Location**	**Cost**	**Status**	**PER % W.I.**	**PER % GORR**	**First Month Production BOE/D**	**First Month Revenue (Net PER)**	**Revenue December (Net PER)**	**Reserves (1) (Net PER)**
2003	**Note: There were no wells drilled in 2003 where Petro-Reef was not the operator**								
2004									
Q4	06-07-56-25W4	$7,581	Producing Gas Well	12.50					
Q4	01-20-56-27W4	$3,895	Producing Gas Well	1.04					
2005									
Q1	15-36-55-27W4	$2,056.67	Producing Gas Well	2.09375					
Q2	06-07-55-25W4	$23,092.89	Producing Gas Well	12.50					

EQUIPPING & TIE-IN									
Year	**Location**	**Cost**	**Status**	**PER % W.I.**	**PER % GORR**	**First Month Production BOE/D**	**First Month Revenue (Net PER)**	**Revenue December (Net PER)**	**Reserves (1) (Net PER)**
2003	**Note: There were no wells drilled in 2003 where Petro-Reef was not the operator**								
2004									
Q4	06-07-56-25W4	$9,397	Producing Gas Well	60.9375		147.30	$3,795	$3,683	
Q4	01-20-56-27W4	$4,236	Producing Gas Well	1.04		9.35	$226	$227	2
Q4	15-25-56-25W4	$2,756	Producing Gas Well	1.2750257	9.00	98.20	$3,610	$8,311	31
2005	**Note: There were no wells equipped or tied-in where Petro-Reef was not the operator**								

Note (1) Reserves as determined by independent engineering appraisal at the end of each year that the well is drilled in (proved reserves only).

The following table represents the pro-forma budget and cash flow for 2006 as prepared by management in respect of revenues expected, less expenses (royalties, operating, interest, general and administrative and professional fees), cash flow, capital expenditures, and net cash flow for the periods indicated.

PETRO-REEF CASH FLOW AND PRO-FORMA BUDGET FOR 2006
QUARTER ENDED (000s)

	March 31	June 30	Sept. 30	Dec. 31	Total
Gross Crude Oil & Natural Gas Revenue	$2,567	$2,900	$3,500	$4,000	$12,967
Expenses					
Royalties & Operating	1,021	1,160	1,400	1,600	5,181
Interest	-	20	42	42	104
General and Administrative	140	196	332	192	860
Total Expenses	**1,161**	**1,376**	**1,774**	**1,834**	**6,145**
Cash Flow (before Capital)	1,406	1,524	1,726	2,166	6,822
Capital Cost					
-Drilling, Completion & Tie-In	190	-	3,145	2,487	5,822
-Seismic & Land	182			318	500
Net Cash Flow (After Capital)	**$1,034**	**$1,524**	**($1,419)**	**($639)**	**$500**

Petro-Reef's short-term requirements for cash are met by cash on hand, current cash flow from operations and bank financing. Management has determined that Petro-Reef's cash flow estimates can be attained through a combination of these sources. Long-term cash requirements will depend on the success of the drilling program. Currently, long-term financing is done with bank financing and current cash flow from operations. Consideration for future financing will include increase in bank financing, and issuance of shares from treasury. The company is not nor does it expect to be in default of any of its obligations.

The National Bank of Canada has made available to Petro-Reef two sources of financing. Credit Facility A is a revolving line of credit for $2 million, at prime plus one and 1.5 percent. Credit Facility B is for acquisitions and development in the amount of $500,000 at prime plus 1.5 percent.

On September 16, 2005, the Corporation raised $1,575,000 by private placement of 3.5 million units. The units were priced at $0.45 and consist of one Common Share and one Purchase Warrant. Each Purchase Warrant entitles the holder to purchase one additional Common Share at an exercise price of $0.70 per Common Share, for a period of 18 months from closing of the private placement (i.e. up to March 16, 2007).

The first financing closed on August 18, 2005 for 1,277,776 Units for an aggregate consideration of $575,000. The balance of the offering closed on September 15, 2005.

Petro-Reef has no off-balance sheet arrangements.

As the time of writing this report Petro-Reef is not considering any proposed acquisitions or dispositions outside the normal course of business. If, as and when a transaction is proposed, and finalized it shall be reported as required.

The present office lease agreement expires on September 30, 2006. Future lease payments to the end of the lease term under the company's office lease will total $31, 531.

The financial statements of Petro-Reef have been prepared in accordance with accounting principles generally accepted in Canada. Management has made the necessary estimates and assumptions regarding certain types of assets, liabilities, revenues and expenses in the preparation of the financial statements. Accordingly, actual results may differ from estimated amounts but management does not believe such differences will materially affect the company's financial position or results of operations.

Effective January 1, 2004, the Company adopted the new Canadian accounting standard for asset retirement obligations. The new standard requires the Company to record the present value of future asset retirement obligations as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development, and/or normal use of the assets. The associated asset retirement costs are capitalized as part of the carrying amount of the property, plant and equipment and depleted and depreciated using a unit of production method over estimated gross proved reserves. Subsequent to the initial measurement of the asset retirement obligation, the obligation is adjusted at the end of each period to reflect the passage of time (accretion), and changes in the estimated future cash flows underlying the obligation. The effect of adoption of the new standard on the financial statements is disclosed below.

The total future asset retirement obligation was estimated based on the Company's net ownership in all wells and facilities, estimated costs to reclaim and abandon the wells and the estimated timing of costs to be incurred in future periods. The Company has estimated the net present value of its asset retirement obligation to be $217,915 (2004 – $155,456) as at December 31, 2005 based on a total future liability of $389,677 (2004 – 279,714), which will be incurred between 2005 and 2025. A credit adjusted risk free rate of 6.08 percent (2004 – 7.5 percent) and an inflation rate of two percent were used to calculate the fair value of the asset retirement obligation.

A reconciliation of the asset retirement obligation is provided below:

	2005	2004
Balance, beginning of year	$ 155,456	$ 190,436
Liabilities incurred in year	64,423	4,638
Liabilities settled in year	(15,229)	(48,583)
Revisions to estimate	--	(4,638)
Accretion expense	13,265	13,603
Balance, end of year	$ 217,915	$ 155,456

STOCK OPTIONS

The authorized share capital of the company is comprised of an unlimited number of preferred shares and an unlimited number of common shares. Details of the changes in the company's issued share capital during 2005 and 2004 are as follows:

	2005		2004	
Common Shares	**Number of shares**	**Amount $**	**Number of shares**	**Amount $**
Balance – Beginning of year	17,738,937	4,772,876	17,688,937	4,743,176
Issued for the exercise of:				
Stock options	200,000	101,060	50,000	29,700
Unit private placement	3,499,987	874,995	3,499,987	--
Share issue costs (net of $86,500 of tax)	--	190,317	--	--
Balance – End of year	**21,438,924**	**5,558,614**	**17,738,937**	**4,772,876**

Basic and diluted earnings (loss) per common share are calculated using the weighted average number of common shares outstanding during the year of 18,994,641 (2004 – 17,701,232).

The increase in share capital as a result of the exercise of stock options is comprised of the amount of cash received of $15,000 and the compensation expense previously recognized of $14,700.

The company has a stock option plan for directors, officers and key employees. The exercise price of each option equals the market price of the company's stock on the date of grant. Options are vested over three years and expire after a maximum exercise period of five years from the date of issuance. A summary of the status of the company's stock option plan as of December 31, 2004 and 2003 and changes during the year is presented below:

	2005		2004	
	Number of Options	**Weighted Average Exercise Price**	**Number of Options**	**Weighted Average Exercise Price**
Balance beginning of year	1,510,000	$ 0.49	1,310,000	$ 0.42
Granted	810,000	0.50	350,000	0.70
Exercised	(200,000)	(0.40)	(50,000)	(0.30)
Expired	-	-	(100,000)	(0.42)
Balance end of year	2,120,000	$ 0.50	1,510,000	$ 0.49
Exercisable end of year	1,310,000	$ 0.50	1,160,000	$ 0.43

The following table summarizes information about stock options outstanding at December 31, 2005:

	Options outstanding			Options exercisable
Exercise Price	Number Outstanding	Weighted Average Remaining Contractual Life	Number Exercisable	Weighted Average Remaining Contractual Life
$0.30	10,000	2.04	10,000	2.04
0.42	700,000	2.52	700,000	2.52
0.49	250,000	0.60	250,000	0.60
0.50	800,000	4.54	-	-
0.52	10,000	4.65	-	-
0.70	300,000	3.46	300,000	3.46
0.71	50,000	3.22	50,000	3.22
	2,120,000	3.19	1,310,000	2.40

Compensation cost of $176,308 (2004 - $300,649) has been recognized for stock options granted during the year.

The weighted average fair value of each option granted during the year ended December 31, 2005 is estimated on the date of grant using the Black-Scholes options pricing model with the following weighted average assumptions:

	2005	2004
Fair value of options granted ($/share)	$ 0.33	$ 0.60
Risk-free interest rate (%)	3.40	4.24
Expected life (years)	3	3
Expected volatility (%)	102	133
Expected dividend yield (%)	-	-

CONTRIBUTED SURPLUS

	2005	2004
Balance – Beginning of year	$380,060	$94,111
Stock based compensation expense	$176,308	$300,649
Adjustment for options exercised in the year	($22,060)	($14,700)
Balance – End of year	$120,000	$380,060

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RESERVES REPORT

Form 51-101F1

Petro-Reef's proved plus probable reserves, based on an independent engineering year-end evaluation, indicated an increase of 14.4 percent to 503.5 MBOE from 440.0 MBOE in the previous year, after extensions, technical revisions, and net production of 66.305 MBOE.

Reserves were 99.99% natural gas and 0.01% crude oil and natural gas liquids. Reserve replacement ratio was 2.41 to 1.

Of the total net reserves reported (using forecast prices) Petro-Reef's reserves are 74.3% proved and 25.7 probable.

Reserves are classified according to the degree of certainty associated with the estimates.

1) Proved Reserves

Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

2) Probable Reserves

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

3) Possible Reserves

Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves. Possible reserves have not been considered in this report.

RESERVES RECONCILIATION

The December 31, 2005 evaluation was prepared using definitions in accordance with National Instrument 51-101. Estimates are prepared such that there is a 90% probability that at least the estimated proved reserves will be recovered and a 50% probability that at least the sum of the estimated proved reserves plus probable reserves will be recovered. The reserves reconciliation reflects current proved plus probable reserves. Both the December 31, 2004 and the December 31, 2005 reports were prepared by Sproule Associates Limited.

1) Reserves Value

Using a ten percent (10%) NPV, the value of proved plus probable reserves at constant prices and Costs (before Income Taxes) increased by One hundred and One percent (101%) compared with last year's established reserves.

2) Reserve Life Index (as at December 31, 2005).

Based on established reserves and production volumes, Petro-Reef's reserve life index was 23 years at the end of 2005 compared with 32.6 years at the end of 2004. Petro-Reef's reserve life index (RLI) is an indication of the number of years it would take to deplete the Company's reserves. The RLI is obtained by dividing the year end reserves by the average daily production of oil, natural gas and natural gas liquids for a calendar year as estimated and determined by the independent reserves evaluator.

3) Evaluation Standards

This report has been prepared by Sproule Associates Limited using state-of-the-art geological and engineering knowledge and techniques. It has been prepared with the Code of Ethics of the Association of Professional Engineers, Geologists and Geophysicists of Alberta ("APEGGA"). Finally, this report adheres in all material aspects to the "best practices" recommended in the COGE Handbook which are in accordance with principals and definitions established by the Calgary Chapter of the Society of Petroleum Evaluation Engineers. The COGE Handbook is incorporated by reference in National Instrument 51-101.

4) The Evaluation of the petroleum and natural gas

The Evaluation of the petroleum and natural gas reserves of Petro-Reef Resources Ltd. has been approved by the company's reserve committee and the board of directors.

5) Statement of Reserves Data

Following is a detailed report on the reserves and future net revenue in six parts:

Part 1	Date of Statement
Part 2	Disclosure of Reserves Data
Part 3	Pricing Assumptions
Part 4	Reconciliation's of changes in Reserves and Future Net Revenue
Part 5	Additional Data Relating to Reserves Data
Part 6	Other Oil and Gas Information

FORM 51-101F1
STATEMENT OF RESERVES DATA
AND OTHER OIL AND GAS INFORMATION

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PART 1 DATE OF STATEMENT

1.1 Relevant Dates

1. Date the statement: April 04, 2006
2. Effective date: December 31, 2005
3. Preparation date: Between February 1 and March 21, 2006

PART 2 DISCLOSURE OF RESERVES DATA

2.1 Reserves Data (Forecast Prices and Costs)

2.1.1 Reserves Gross and Net (Forecast Prices and Costs)

N1 51-101
Summary of Oil and Gas Reserves
as of December 31, 2005
Forecast Prices and Costs

Reserves

	Light and Medium Oil		Heavy Oil		Natural Gas Liquids (non-associated & associated)		Natural Gas (solution)		Natural Gas Liquids	
Reserves Category	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (MMcf)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**
Proved										
Developed Producing	0	0	0	0	1,457	1,137	0	0	1	0
Developed Non-Producing	0	0	0	0	724	575	0	0	0	0
Undeveloped	0	0	0	0	650	529	0	0	0	0
Total Proved	**0**	**0**	**0**	**0**	**2,831**	**2,241**	**0**	**0**	**1**	**0**
Probable	0	0	0	0	923	776	0	0	0	0
Total Proved Plus Probable	**0**	**0**	**0**	**0**	**3,754**	**3,017**	**0**	**0**	**1**	**1**

2.1.2 Net Present Value of Future Net Revenue (Forecast Prices and Costs)

N1 51-101
Summary of Net Present Values of Future Net Revenue
as of December 31, 2005
Forecast Prices and Costs

	Net Present Values of Future Net Revenue									
	Before Income Taxes Discounted at (% / Year)					After Income Taxes Discounted at (% / Year)				
Reserves Category	**0 (M$)**	**5 (M$)**	**10 (M$)**	**15 (M$)**	**20 (M$)**	**0 (M$)**	**5 (M$)**	**10 (M$)**	**15 (M$)**	**20 (M$)**
Proved										
Developed Producing	10,710	9,974	9,381	8,892	8,480	9,905	9,211	8,654	8,197	7,813
Developed Non-Producing	4,560	3,652	3,040	2,606	2,284	3,283	2,591	2,134	1,815	1,581
Undeveloped	2,862	2,378	2,012	1,727	1,501	1,956	1,602	1,336	1,131	969
Total Proved	**18,132**	**16,004**	**14,433**	**13,225**	**12,265**	**15,143**	**13,404**	**12,125**	**11,143**	**10,363**
Probable	4,624	3,572	2,903	2,445	2,112	3,187	2,425	1,941	1,611	1,371
Total Proved Plus Probable	**22,756**	**19,576**	**17,336**	**15,670**	**14,378**	**18,329**	**15,829**	**14,066**	**12,754**	**11,734**

Notes:

1) NPV of FNR include all resource income:
   - Sale of oil, gas, by-product reserves
   - Processing third party reserves
   - Other income

2) Income Taxes
   - Includes all resource income
   - Apply appropriate income tax calculations
   - Include prior tax pools

2.1.3 Future Net Revenue Undiscounted (Forecast Prices and Costs)

N1 51-101
Total Future Net Revenue
Undiscounted
as of December 31, 2005
Forecast Prices and Costs

Reserves Category	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Develop-ment Costs (M$)	Well Abandon-ment/ Other Costs (M$)	Future Net Revenue Before Income Taxes (M$)	Income Taxes (M$)	Future Net Revenue After Income Taxes (M$)
Proved	29,912	4,773	6,106	735	166	18,132	2,989	15,143
Proved Plus Probable	39,261	6,367	8,528	1,410	200	22,756	4,426	18,329

2.1.4 By Production Group-Future Net Revenue before Income Tax (Using Forecast Prices and Costs – Using a discount rate of 10%)

N1 51-101
Net Present Value of Future Net Revenue
By Production Group
as of December 31, 2004
Constant Prices and Costs

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10% Year) (M$)
Proved	Light and Medium Crude Oil (including solution gas and associated by-products)	0
	Heavy Oil (including solution gas and associated by-products)	0
	Natural Gas (including associated by-products)	12,910
	Coalbed Methane (including associated by-products)	0
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and associated by-products)	0
	Heavy Oil (including solution gas and associated by-products)	0
	Natural Gas (including associated by-products)	15,642
	Coalbed Methane (including associated by-products)	0

2.2 Reserves Data (Constant Prices and Costs)

2.2.1 Reserves Gross and Net (Constant Prices and Costs)

N1 51-101
Summary of Oil and Gas Reserves
as of December 31, 2005
Constant Prices and Costs

Reserves

	Light and Medium Oil		Heavy Oil		Natural Gas Liquids (non-associated & associated)		Natural Gas (solution)		Natural Gas Liquids	
Reserves Category	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Gross (MMcf)**	**Net (MMcf)**	**Net (MMcf)**	**Net (MMcf)**	**Net (MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**
Proved										
Developed Producing	0	0	0	0	1,507	1,174	0	0	1	1
Developed Non-Producing	0	0	0	0	724	575	0	0	0	0
Undeveloped	0	0	0	0	650	529	0	0	0	0
Total Proved	**0**	**0**	**0**	**0**	**2,880**	**2,278**	**0**	**0**	**1**	**1**
Probable	0	0	0	0	941	729	0	0	0	0
Total Proved Plus Probable	**0**	**0**	**0**	**0**	**3,821**	**3,071**	**0**	**0**	**1**	**1**

2.2.2 Net Present Value of Future Net Revenue (Constant Prices and Costs)

NI 51-101
Summary of Net Present Values of
Future Net Revenue
as of December 31, 2005
Constant Prices and Costs

	Net Present Values of Future Net Revenue									
	Before Income Taxes Discounted at (% / Year)					After Income Taxes Discounted at (% / Year)				
Reserves Category	**0 (M$)**	**5 (M$)**	**10 (M$)**	**15 (M$)**	**20 (M$)**	**0 (M$)**	**5 (M$)**	**10 (M$)**	**15 (M$)**	**20 (M$)**
Proved										
Developed Producing	11,055	10,072	9,314	8,711	8,219	10,397	9,404	8,680	8,118	7,665
Developed Non-Producing	5,615	4,355	3,529	2,956	2,541	3,779	2,933	2,378	1,993	1,713
Undeveloped	3,655	2,955	2,440	2,050	1,748	2,467	1,972	1,610	1,337	1,125
Total Proved	**20,325**	**17,382**	**15,283**	**13,718**	**12,507**	**16,643**	**14,309**	**12,668**	**11,447**	**10,503**
Probable	5,794	4,278	3,355	2,746	2,316	3,908	2,865	2,225	1,800	1,499
Total Proved Plus Probable	**26,119**	**21,660**	**18,639**	**16,464**	**14,823**	**20,551**	**17,173**	**14,892**	**13,247**	**12,002**

Notes:

1) NPV of FNR include all resource income:
   - Sale of oil, gas, by-product reserves
   - Processing third party reserves
   - Other income

2) Income Taxes
   - Includes all resource income
   - Apply appropriate income tax calculations
   - Include prior tax pools

2.2.3 Future Net Revenue Undiscounted (Constant Prices and Costs)

N1 51-101
Total Future Net Revenue
(Undiscounted)
as of December 31, 2005
Constant Prices and Costs

Reserves Catergory	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Development Costs (M$)	Well Abandonment / Other Costs (M$)	Future Net Revenue Before Income Taxes (M$)	Income Taxes (M$)	Future Net Revenue After Income Taxes (M$)
Proved Reserves	31,659	4,717	5,742	735	140	20,325	3,682	16,643
Proved Plus Probable	42,067	6,422	7,953	1,410	163	26,119	5,568	20,551

2.2.4 By Production Group-Future Net Revenue before Income Tax (Using Forecast Prices and Costs – Using a discount rate of 10 percent). (Before Income Tax)

N1 51-101
Net Present Value of Future Net Revenue
By Production Group
As of December 31, 2004
Forecast Prices and Costs

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10% / Year) (M$)
Proved Reserves	**Light and Medium Crude Oil (including solution gas and associated by-products)**	0
	Heavy Oil (including solution gas and associated by-products)	0
	Natural Gas (including associated by-products)	15,283
	Coalbed Methane (including associated by-products)	0
Proved Plus Probable Reserves	**Light and Medium Crude Oil (including solution gas and associated by-products)**	0
	Heavy Oil (including solution gas and associated by-products)	0
	Natural Gas (including associated by-products)	18,639
	Coalbed Methane (including associated by-products)	0

PART 3 PRICING ASSUMPTIONS

3.1 Forecast Prices Used in Estimates

N1 51-101
Summary of Pricing and
Inflation Rate Assumptions
as of December 31, 2005
Forecast Prices and Costs

	Oil							
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Medium 29.3° API ($Cdn/bbl)	Natural Gas [1] AECO Gas Prices ($Cdn/MMBtu)	Pentanes Plus F.O.B Field Gate ($Cdn/bbl)	Butanes F.O.B. Gate ($Cdn/bbl)	Inflation Rate [2] (%/Yr)	Exchange Rate [3] ($US/$Cdn)
Historical								
2001	25.94	39.06	31.56	6.23	42.46	27.93	2.0	0.646
2002	26.09	40.12	35.46	4.04	40.80	25.39	2.7	0.637
2003	31.14	43.23	37.53	6.66	44.16	34.55	2.5	0.716
2004	41.42	52.91	45.72	6.87	53.91	41.37	2.5	0.825
2005	56.45	69.28	57.38	8.58	69.13	45.20	1.6	0.850
Forecast								
2006	60.81	70.07	59.62	11.58	71.77	47.01	2.5	0.850
2007	61.61	70.99	60.39	10.84	72.71	47.62	2.5	0.850
2008	54.60	62.73	53.48	8.95	64.25	42.08	2.5	0.850
2009	50.19	57.53	49.18	7.87	58.92	38.59	1.5	0.850
2010	47.76	54.65	46.75	7.57	55.97	36.66	1.5	0.850
Thereafter	Various Escalation Rates							

1) This summary table identifies benchmark reference pricing schedules that might apply to a *reporting issuer*.
2) Inflation rates for forecasting prices and costs.
3) Exchange rates used to generate the benchmark reference prices in this table.

Notes:
Product sale prices will reflect these reference prices with further adjustments for quality and transportation to point of sale.

3.2 Constant Prices Used in Estimates

N1 51-101
Summary of Pricing Assumptions
as of December 31, 2005
Constant Prices and Costs

Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Medium 29.3° API ($Cdn/bbl)	Natural Gas [1] AECO Gas Prices ($Cdn/MMBtu)	Pentanes Plus F.O.B Field Gate ($Cdn/bbl)	Butanes F.O.B. Gate ($Cdn/bbl)	Exchange Rate [3] ($US/$Cdn)
Historical							
Dec. 31, 2000	26.83	39.57	32.58	13.34	48.63	46.69	0.667
Dec. 31, 2001	19.78	31.15	22.41	3.64	29.25	16.73	0.628
Dec. 31, 2002	31.23	49.26	41.95	5.97	50.22	38.91	0.634
Dec. 31, 2003	32.56	40.60	36.39	6.88	44.18	37.73	0.771
Dec. 31, 2004	44.04	46.51	32.10	6.78	51.80	39.78	0.832
Forecast							
Dec. 31, 2005	61.04	68.12	52.28	9.99	71.35	59.32	0.860

1) This summary table identifies benchmark reference pricing schedules that might apply to a *reporting issuer*.
2) Exchange rates used to generate the benchmark reference prices in this table.

Notes:
Product sale prices will reflect these reference prices with further adjustments for quality and transportation to point of sale.

PART 4 RECONCILIATIONS OF CHANGES IN RESERVES AND FUTURE NET REVENUE

4.1 Reserves Reconciliation

N1 51-101
Reconciliation of Company Net Reserves (After Royalty)
By Principal Product Type
as of December 31, 2005
Forecast Prices and Costs [1]

	Light and Medium Oil			Associated and Non-Associated Gas			Natural Gas Liquids		
Factors	**Net Proved (Mbbl)**	**Net Probable (Mbbl)**	**Net Proved Plus Probable (Mbbl)**	**Net Proved (MMcf)**	**Net Probable (MMcf)**	**Net Proved Plus Probable (MMcf)**	**Net Proved (Mbbl)**	**Net Probable (Mbbl)**	**Net Proved Plus Probable (Mbbl)**
December 31, 2003	**0**	**0**	**0**	**1,615**	**928**	**2,543**	**11.6**	**4.5**	**16.1**
Extensions	-	-	-	1,208	319	1,527	0.3	0.1	0.4
Improved Recovery	-	-	-	-	-	-	-	-	-
Technical Revisions	-	-	-	(243)	(471)	(714)	(10.4)	(4.3)	(14.7)
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-
Production	-	-	-	(339)	0	(339)	(0.7)	0	(0.7)
December 31, 2004	**0**	**0**	**0**	**2,241**	**776**	**3,017**	**0.5**	**0.2**	**0.7**

(1) A reconciliation of *reserves* estimates may be presented using either *constant prices and costs* or *forecast prices and costs* provide that the price and cost case is indicated in the disclosure.
(2) The numbers may not match due to rounding.
(3) Technical revision includes reserves reclassification.

4.2 Future Net Revenue Reconciliation (Forecast Prices & Costs)

For Proved Reserves Only @ 10% Discount of Net Present Value (Before Income Tax)

	Oil & Non-Associated Gas Proved Only @ 10% NPV $
Starting Balance @ December 31, 2004	5,875
2005 Production	-2,193
Acquisitions	0
Discoveries [1]	6,560
Net Revisions [2]	4,191
Closing Balance December 31, 2005	14,433

Note 1: Discoveries of proved reserves were assigned by the independent reserves evaluator to two (2) new wells in the Alexander Field.

Note 2: Net Revisions of $4,191,000 were mainly due to improved recoveries as recognized by the independent reserves evaluator and reserve additions from probable to proved category from 2004 to the end of December 31, 2005.

4.2.1 Additional changes were due to changes used in the Forecast Price forecast for December 31, 2004 and December 31, 2005 as follows:

	December 31, 2004 Price ($)	**December 31, 2005 Price ($)**
Oil : Edmonton Par	46.51	70.07
Natural Gas (AECO-C)	6.78	11.58
Natural Gas By Products:		
Butanes	39.78	47.01
Pentanes Plus	51.80	71.77
Exchange Rate	0.832	0.850

4.2.2 The change in future net development costs of proved undeveloped reserves from December 31, 2004 to December 31, 2005 is as a result of increased cost in drilling, completions and facilities

4.2.3 The net change in income taxes are due to increases in projected net revenues effective December 31, 2005, versus the projected net reserves effective Decelmber 31, 2004 and the increase in capital expenditures on properties during fiscal year 2005.

The changes in tax pools are as follows:

FEDERAL:

	COGPE		CDE		CEE		Class 39 & 41	Class 8 & 45	Total
	Regular	Successor	Regular	Successor	Regular	Successor			
	($)	($)	($)	($)	($)	($)	($)	($)	($)
Opening balance per Tax return	731,228	588,914	473,629	4,561	2,965,976	0	1,223,106	25,622	6,013,036
Additions for 2005	233,776	0	3,237	0	1,315,109	0	697,345	4,591	2,381,173
Tax pool available	965,004	588,914	476,866	4,561	4,281,085	0	1,920,451		8,394,209
Tax claim rate (%)	10%	10%	30%	30%	100%	100%	25% 12.5%	20% 45%	
Claim Available	96,500	58,891	143,060	1,368	4,281,085	0	90,350 392,944	5,950	5,106,914
Current year claim	96,500	58,891	143,060	1,368	1,501,492	0	0	660	1,801,971
Closing balance per Tax return	868,504	530,023	333,806	3,193	2,906,708	0	1,920,451	29,553	6,592,238

PART 5 ADDITIONAL INFORMATION RELATING TO RESERVES DATA

5.1 Undeveloped Reserves

5.1.1 Proved Undeveloped Reserves

Proved Undeveloped Reserves are those reserves expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production and meet the proved developed or proved developed producing reserves classification. Total net capital expenditures for 2005 are anticipated to be $726,000.

5.1.2 Probable Undeveloped Reserves

Probable Undeveloped Reserves are those reserves expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production to meet the proved developed or proved developed producing reserves classification from the current probable undeveloped classification. Total net capital expenditures for 2006 are anticipated to be $675,000.

5.2 Significant Factors or Uncertainties

There are no economic factors or significant uncertainties that affect particular components of the reserves data.

5.3 Future Development Costs

5.3.1 Development Costs of Future Net Revenue

Proved Reserves (Constant Prices and Costs)		Proved Reserves (Forecast Prices and Costs)		Proved Plus Probable Reserves (Forecast Prices and Costs)	
Undiscounted	Discount @ 10%	Undiscounted	Discount @ 10%	Undiscounted	Discount @ 10%
$735,000	$687,000	$735,000	$687,000	$1,410,000	$1,348,000

5.3.2 Development Costs of Future Net Revenue (by year)

a) Proved Reserves (Constant Prices and Costs)

2006	$732,000
2007	0
2008	0
2009	0
2010	0

b) Proved Reserves (Forecast Prices and Costs)

2006	$732,000
2007	0
2008	0
2009	0
2010	0

c) Proved Plus Probable Reserves (Forecast Prices and Costs)

2006	$1,407,000
2007	0
2008	0
2009	0
2010	0

PART 6 OTHER OIL AND GAS INFORMATION

6.1 Oil and Gas Properties and Wells

Petro-Reef's two main properties representing 97.3% of its net present value (for proved plus probable reserves using 10% discounted values – before income taxes) are located in Central Alberta.

6.1.1 Producing Versus Non-Producing Reserves

Following are properties to which reserves have been attributed and are capable of producing but which are not producing as of the effective date, the percentage of those reserves to the total reserves, and the percentage of those reserves that are non-producing as of the date of this statement.

a) (i) Alexander
Total Proved plus Probable Reserves

CRUDE OIL			NATURAL GAS *		
	Company			Company	
Gross MBbl	Gross MBbl	Net MBbl	Gross MMCF	Gross MMCF	Net MMCF
0	0	0	6,514	2,556	2,001

(ii) Proved plus Probable Non-Producing Reserves (@ Dec. 31, 2005)

CRUDE OIL			NATURAL GAS *		
	Company			Company	
Gross MBbl	Gross MBbl	Net MBbl	Gross MMCF	Gross MMCF	Net MMCF
	0	0	2,285	929	760
Percentage of Total Reserves Non-Producing	0%	0%		36.3%	38.0%

(iii) Total Proved plus Probable Non-Producing Reserves (@ April 04, 2006)

CRUDE OIL			NATURAL GAS *		
	Company			Company	
Gross MBbl	Gross MBbl	Net MBbl	Gross MMCF	Gross MMCF	Net MMCF
	0	0	2,285	929	760
Percentage of Total Reserves Non-Producing	0%	0%		36.3%	38.0%

*** Includes solution gas**

b) Morinville

(i) Total Proved plus Probable Reserves

CRUDE OIL			NATURAL GAS *		
	Company			Company	
Gross MBbl	Gross MBbl	Net MBbl	Gross MMCF	Gross MMCF	Net MMCF
0	0	0	2,573	1,155	979

(ii) Total Proved plus Probable Non-Producing Reserves (@ Dec. 31, 2004)

CRUDE OIL			NATURAL GAS *		
	Company			Company	
Gross MBbl	Gross MBbl	Net MBbl	Gross MMCF	Gross MMCF	Net MMCF
	0	0	1,830	951	756
Percentage of Total Reserves Non-Producing	0%	0%		82.3%	77.2%

(iii) Total Proved plus Probable Non-Producing Reserves (@ April 01, 2005)

CRUDE OIL			NATURAL GAS *		
	Company			Company	
Gross MBbl	Gross MBbl	Net MBbl	Gross MMCF	Gross MMCF	Net MMCF
	0	0	1,830	951	756
Percentage of Total Reserves Non-Producing	0%	0%		82.3%	77.2%

*** Includes solution gas**

c) Other Properties

Other properties represent 2.7% of the total net present value (before income tax) with approximately 95% of those properties producing. The other properties are all non-operated.

6.1.2 Producing Versus Non-Producing Oil & Gas Wells:

Following is a list of oil and gas wells (gross and net) which are producing and non-producing. All the oil and gas-wells are in Central Alberta Canada.

Production is as of the preparation date of April 04, 2005

	Oilwells		Gaswells	
	Gross	Net	Gross	Net
Producing	0	0	14	4.63378
Non-Producing @ April 04, 2006	0	0	5	2.3291

Note: Only wells which have reserves assigned by the qualified independent reserves evaluator have been reported.

6.2 Properties With No Attributed Reserves

6.2.1 Unproved Properties [(1)]

Location	Gross (Acres)	Net (Acres)
Alexander (Qui Barre)	7,448	3,767
Morinville	1,920	792
Total Unproved Properties	9,368	4,559

Note 1: Unproved Properties are those lands which have no reserves assigned by the independent reserves evaluator.

There are no work commitments required for fiscal year 2005.

6.2.2 The net area of unproved property which is expected to expire in fiscal year 2006 is 611 acres.

6.3 Forward Contracts

The Company is not bound by any agreement (including any transportation agreement) which would preclude it from fully realizing future market prices for oil or gas.

6.4 Additional Information Concerning Abandonment and Reclamation Costs.

a) Petro-Reef estimates abandonment and reclamation cost based on historical average costs for the area net of salvage value at $30,000 per well.

b) Future net wells for which such costs shall be incurred are:
(i) For Wells where reserves are assigned equals 6.963 net wells.
(ii) For Wells where no reserves are assigned equals 1.7325 net wells.

c) Undiscounted cost to the Company = $181,788,060 for reclamation and abandonment.

d) The qualified independent reserves evaluator has estimated $200,000 for abandonment and reclamation net to the Company before recovery of equipment or salvage value.

e) The company expects to pay approximately $50,000 in the next three years for reclamation and abandonment.

6.5 Tax Horizon

The Company does not expect to be required to pay income taxes for its 2005 financial year. It is anticipated that taxes will become payable for fiscal year 2007 or 2008.

6.6 Costs Incurred (for fiscal year 2005)

6.6.1 Cost for COGPE, CEE, and CDE ($)

a) Property acquisition costs (COGPE) = 233,776
b) Exploration costs (CEE) = 1,315,109
c) Development costs (CDE) = 3,237
d) Class 39 & 41 = 697,345
e) Class 8 = 4,591
f) Total = 2,381,173

6.7 Exploration and Development Activities

6.7.1 Wells for fiscal year 2005

Exploration wells	3
Development wells	0

6.7.2 Wells for fiscal year 2005

Gaswells	2
Oilwells	0
Dry Holes	1

6.8 Production Estimates

6.8.1 Production estimates for 2006 (based on Company Interest) are:

a) Using Constant Prices and Costs

	Oil	0 Bbl
	Gas	2,292 MMCF
	NGL	0 Bbl

b) Using Forecast Prices and Costs

Proved:	Oil	0 Bbl
	Gas	2,197 MMCF
	NGL	0 Bbl

Proved Plus Probable:	Oil	0 Bbl
	Gas	2,502 MMCF
	NGL	0 Bbl

Note: Production estimates are taken from the evaluation by the independent reserves evaluator and in the Companies opinion are extremely conservative as required by N1 51-101.

6.8.2 Of the above referenced production 89.4% is represented by two (2) properties:

a) Morinville
b) Alexander

6.9 Production History for fiscal year 2005

2005 PRODUCTI0N & REVENUE SUMMARY

Month	Production BOE / Day	Production BOE / Month	Price $ / BOE	Royalty Expenses $/BOE	Gross Revenue $ After Royalties	Operating Expenses $	Netback $/BOE	Cash*Flow $
JAN	237.66	7,367.51	42.17	9.59	240,030.63	64,643.59	23.81	175,387.04
FEB	241.92	6,773.74	42.63	8.95	228,094.00	59,529.17	24.89	168,564.83
MAR	231.99	7,191.67	47.82	9.57	275,069.07	60,307.95	29.86	214,761.12
3 Month Average	**237.19**	**7,110.97**	**44.21**	**9.37**	**247,727.90**	**61,493.57**	**26.19**	**186,237.66**
APR	186.97	5,609.23	50.49	10.69	223,250.54	54,385.15	30.10	168,865.39
MAY	160.33	4,970.16	44.72	8.89	178,060.67	38,870.44	28.01	139,190.23
JUN	99.55	2,986.45	47.14	6.49	121,385.70	75,196.28	15.47	46,189.42
3 Month Average	**148.95**	**4,521.95**	**47.45**	**8.69**	**174,232.30**	**56,150.62**	**24.53**	**118,081.68**
JUL	99.86	3,095.79	58.14	10.24	148,302.11	62,789.33	27.62	85,512.78
AUG	125.85	3,901.35	58.91	9.73	191,860.80	59,278.69	33.98	132,582.11
SEP	127.53	3,825.79	69.68	11.96	220,824.44	63,607.76	41.09	157,216.08
3 Month Average	**117.75**	**3,607.64**	**62.24**	**10.64**	**186,995.78**	**61,891.93**	**34.22**	**125,103.86**
OCT	100.25	3,107.61	79.04	12.90	205,535.08	49,190.15	50.31	156,344.93
NOV	113.96	3,418.72	59.34	11.56	163,315.48	43,393.77	34.20	116,921.71
DEC	456.16	14,141.01	76.83	17.93	832,888.28	19,524.69	50.44	713,313.59
3 Month Average	**223.46**	**6,889.11**	**71.74**	**14.13**	**400,579.61**	**37,386.20**	**44.98**	**328,860.08**
Average for 2005	181.61	5,525.42	57.28	10.96	255,972.61	47,975.25	34.90	155,056.84
Total for 2005	-	**66,305.03**	-	-	**3,071,671.35**	**575,703.00**	-	**1,860,682.05**

* Note: Cash flow on this production and revenue summary is before ARTC, general and administrative costs, interest expense, and before income tax.

PETRO-REEF RESOURCES LTD.

Financial Statements

December 31, 2004 and 2005

PRICEWATERHOUSECOOPERS

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Chartered Accountants
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Canada T2P 5L3
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April 19, 2006

Auditors' Report

To the Shareholders of
Petro-Reef Resources Ltd.

We have audited the balance sheets of **Petro-Reef Resources Ltd.** as at December 31, 2005 and 2004 and the statements of operations and deficit and cash flows for the years then ended. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the company as at December 31, 2005 and 2004 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants

PricewaterhouseCoopers refers to the Canadian firm of PricewaterhouseCoopers LLP and the other member firms of PricewaterhouseCoopers International Limited, each of which is a separate and independent legal entity.

PETRO-REEF RESOURCES LTD.
Balance Sheet
As at December 31, 2005 and 2004

	2005	2004
ASSETS		
Current assets		
Cash and cash equivalents	$ 397,904	$ -
Accounts receivable	2,142,072	1,833,691
Prepaid expenses and deposits	11,192	6,072
	2,551,168	1,839,763
Property, plant and equipment (note 2)	7,911,121	6,852,087
	$ 10,462,289	$ 8,691,850
LIABILITIES		
Current liabilities		
Cheques drawn in excess of bank	$ -	$ 411,771
Bank line of credit (note 3)	-	700,000
Accounts payable and accrued charges	3,787,579	3,064,931
	3,787,579	4,176,702
Future income taxes (note 7)	426,827	338,424
Asset retirement obligation (note 4)	217,915	155,456
	4,432,321	4,670,582
SHAREHOLDERS' EQUITY		
Share capital (note 5)	5,558,614	4,772,876
Warrants (note 5)	820,000	-
Contributed surplus (note 5)	534,308	380,060
Deficit	(882,954)	(1,131,668)
	6,029,968	4,021,268
	$ 10,462,289	$ 8,691,850

SIGNED ON BEHALF OF THE BOARD

"Joseph Werner"
Director

"Robert N. Maertens-Poole"
Chief Financial Officer

PETRO-REEF RESOURCES LTD.
Statements of Operations and Deficit
For the years ended December 31, 2005 and 2004

	2005	2004
Revenue		
Oil and gas sales, net of royalties and ARTC	$ 3,224,567	$ 2,162,656
Expenses		
Production	757,703	620,749
Depletion and depreciation	1,380,232	1,471,862
General and administrative	593,896	697,218
Accretion expense	13,265	13,603
Loss on settlement of asset retirement obligation	4,291	12,049
Interest expense	44,990	80,262
	2,794,377	2,895,743
Earnings (loss) before the following	430,190	(733,087)
Interest income	3,427	-
	433,617	(733,087)
Future income tax (recovery) (note 7)	184,903	(191,000)
Net income (loss) for the year	248,714	(542,087)
Deficit - Beginning of year	(1,131,668)	(589,581)
Deficit - End of year	$ (882,954)	$ (1,131,668)
Basic net income (loss) per share	$ 0.01	$ (0.03)
Diluted net income (loss) per share	$ 0.01	$ (0.03)

PETRO-REEF RESOURCES LTD.
Statement of Cash Flows
For the years ended December 31, 2005 and 2004

	2005	2004
Cash provided by (used in)		
Operating activities		
Net income (loss) for the year	$ 248,714	$ (542,087)
Items not effecting working capital		
Accretion expense	13,265	13,603
Depletion and depreciation	1,380,232	1,471,862
Loss on settlement of asset retirement obligation	4,291	12,049
Stock based compensation	176,308	300,649
Future income taxes	184,903	(191,000)
Cash flow from operations	2,007,713	1,065,076
Asset retirement expenditures	(19,520)	(60,632)
Net change in non-cash operating working capital items (note 11)	198,837	510,152
	2,187,030	1,514,596
Financial activities		
Bank line of credit	(700,000)	(450,000)
Proceeds from share issue	1,575,000	-
Share issue costs	(166,822)	-
Proceeds from exercise of stock options	79,000	15,000
	787,178	(435,000)
Investing activities		
Expenditures on property, plant and equipment	(2,374,843)	(1,148,725)
Net change in non-cash investing working capital items (note 11)	210,310	66,832
	(2,164,533)	(1,081,893)
Change in cash and cash equivalents (cheques drawn in excess of bank) **During the period**	809,675	(2,297)
Cheques drawn in excess of bank Beginning of period	(411,771)	(409,474)
Cash and cash equivalents (cheques drawn in excess of bank) **End of period**	$ 397,904	$ (411,771)
Supplemental information		
Interest paid	$ 44,990	$ 80,262

1. Accounting policies

The financial statements of Petro-Reef Resources Ltd. (the "Company") have been prepared in accordance with accounting principles generally accepted in Canada. Management has made the necessary estimates and assumptions regarding certain types of assets, liabilities, revenue and expenses in the preparation of the financial statements. Accordingly, actual results may differ from estimated amounts but management does not believe such differences will materially affect the company's financial position or results of operations.

The Company has a working capital deficit of $1,236,411 as at December 31, 2005 and $2,336,939 as at December 31, 2004. The Company is subject to certain debt covenants pertaining to demand operating facilities (note 3). At December 31, 2005 the Company was in compliance with all covenants.

Significant accounting policies are summarized as follows:

Oil and gas operations

The Company engaged in the exploration for and production of crude oil and natural gas in Canada. The Company follows the full cost method of accounting for crude oil and gas operations whereby all costs related to the acquisition of, exploration for and development of oil and gas reserves are capitalized. Such costs include leasehold acquisition costs, geological and geophysical costs, lease rentals, drilling, plant and equipment costs and related overhead. Government incentives are credited to the cost of the oil and gas properties at the time the expenditures are incurred. Proceeds from the disposal of properties are applied as a reduction of the cost of the remaining assets with no gain or loss recognized, unless such a sale would result in a change of more than twenty percent depletion rate.

The Company places a limit on the carrying value of property, plant and equipment and other assets, which may be depleted against revenues of future periods (the "ceiling test"). The carrying value is assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves using forward pricing, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying value. When the carrying value is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value of assets exceeds the fair value of proved and probable reserves, and the cost, less any impairment, of unproved properties that contain no probable reserves.

Depletion is computed using the unit-of-production method based on gross estimated proved oil and gas reserves (converted to equivalent units on the basis of estimated relative energy content). In determining the appropriate depletion rate, the Company includes the net book value of its oil and gas properties, as well as the estimated future costs to be incurred in developing proved reserves and excludes the unimpaired cost attributable to unproved properties.

Depreciation

Depreciation of furniture and fixtures is calculated using the declining balance method at an annual rate of 20 percent. Depreciation of computer equipment is calculated using the declining balance method at an annual rate of 30 percent.

Asset retirement obligation

The Company records a liability for the fair value of legal obligations associated with the retirement of long-lived tangible assets in the period in which they are incurred, normally when the asset is purchased or developed. On recognition of the liability there is a corresponding increase in the carrying amount of the related asset known as the asset retirement cost, which is depleted on a unit-of-production basis over the life of the reserves. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to earnings, and for revisions to the estimated future cash flows. Actual costs incurred upon settlement of the obligations are charged against the liability.

Stock options

The Company has an incentive stock option plan for employees, officers, directors and consultants as described in note 6. The Company records stock based compensation expense using the fair value method. The fair value of an option is calculated at the grant date, and expensed equally over the vesting term of the option. The Company records the cumulative stock based compensation as a contributed surplus. When options are exercised, contributed surplus is reduced and share capital is increased by the amount of accumulated stock based compensation for the exercised option. Any consideration received on the exercise of stock options is credited to share capital.

Revenue recognition

Revenue associated with the sale of crude oil, natural gas and natural gas liquids owned by the company are recognized when title passes from the company to its customers.

Income taxes

The company follows the liability method of accounting for income taxes. Under this method, the company records future income taxes for the effect of any differences between the accounting and the income tax basis of an asset or liability using income tax rates substantially enacted on the balance sheet date. The effect of a change in income tax rates on the future income tax assets and liabilities is recognized in income in the period of the change.

Earnings per share

The company uses the treasury stock method to determine the dilutive effect of stock options and other dilutive instruments. This method assumes that any proceeds from the exercise of in-the-money stock options or other dilutive instruments are assumed to be used to purchase common shares at the average market price during the period.

Joint ventures

Substantially all of the company's activities are conducted jointly with other industry partners and accordingly, these financial statements reflect only the company's proportionate interest in such activities.

Cash and cash equivalents

Cash and cash equivalents include short-term investments, such as money market deposits or similar type instruments, with a maturity of three months or less when purchased

2. Property, plant, and equipment

	December 31, 2005		
	Cost	Accumulated Depletion and Depreciation	Net
Petroleum and natural gas	$ 13,661,763	$ 5,766,284	$ 7,895,479
Furniture and fixtures	47,113	31,471	15,642
	$ 13,708,876	$ 5,797,755	$ 7,911,121

	December 31, 2004		
	Cost	Accumulated Depletion and Depreciation	Net
Petroleum and natural gas	$ 11,227,089	$ 4,390,336	$ 6,836,753
Furniture and fixtures	42,522	27,188	15,334
	$ 11,269,611	$ 4,417,524	$ 6,852,087

No interest or general and administrative expenses were capitalized during the period. Unproven property costs of $390,069 (2004 – $305,637) have been excluded from capitalized costs subject to depletion.

The company performed a ceiling test calculation at December 31, 2005 in accordance with the policy described in note 1. The oil and gas future prices used in the calculation were based on the company's January 1, 2006 commodity price forecast, which is consistent with the price forecast used by its independent reserve evaluators. These prices have been adjusted for commodity price differentials specific to the company. The following table summarizes the benchmark prices used in the ceiling test calculation.

Year	WTI Oil ($US/bbl)	Foreign Exchange Rate	Edmonton Light (Crude oil) ($Cdn/bbl)	AECO Gas ($Cdn/MMBtu)
2006	60.81	0.85	70.07	11.58
2007	61.61	0.85	70.99	10.84
2008	54.60	0.85	62.73	8.95
2009	50.19	0.85	57.53	7.87
2010	47.76	0.85	54.65	7.57
2011 - 2016	50.33	0.85	57.60	8.03
Escalate thereafter	1.5% per year		1.5% per year	1.5% per year

The ceiling test calculation did not result in any impairment write down at December 31, 2005.

3. Demand operating facilities

Facility A is a revolving operating demand loan with a maximum limit of $2,000,000. Facility B is a non-revolving acquisition/development demand loan that provides an additional $500,000 of financing. Interest is at prime plus 1.25 percent per annum for Facility A and 1.5 percent per annum for the Facility B. At December 31, 2005 the balance owing on the current loan was $Nil (2004 - $700,000).

The facilities are secured by $5,000,000 floating charge debenture over all the Company's assets with a negative pledge and undertaking to provide fixed charges on the Company's major producing properties at the request of the bank. The facilities are repayable on demand and are reviewed periodically by the bank, the next review being scheduled for April 2006.

4. Asset retirement obligation

The total future asset retirement obligation was estimated based on the Company's net ownership in all wells and facilities, estimated costs to reclaim and abandon the wells and the estimated timing of costs to be incurred in future periods. The Company has estimated the net present value of its asset retirement obligation to be $217,915 (2004 - $155,456) as at December 31, 2005 based on a total future liability of $389,677 (2004 – 279,714), which will be incurred between 2005 and 2025. A credit adjusted risk free rate of 6.08 percent (2004 -7.5 percent) and an inflation rate of 2 percent were used to calculate the fair value of the asset retirement obligation.

A reconciliation of the asset retirement obligation is provided below:

	2005	2004
Balance, beginning of year	$ 155,456	$ 190,436
Liabilities incurred in year	64,423	4,638
Liabilities settled in year	(15,229)	(48,583)
Revisions to estimate	--	(4,638)
Accretion expense	13,265	13,603
Balance, end of year	$ 217,915	$ 155,456

5. Share capital

a) Class A common shares

	2005		2004	
	Shares	Amount	Shares	Amount
Balance, beginning of year	17,738,937	$ 4,772,876	17,688,937	$ 4,743,176
Exercise of options	200,000	101,060	50,000	29,700
Unit private placement (i)	3,499,987	874,995	-	-
Share issue costs, (net of $96,500 of tax) (i)	-	(190,317)	-	-
Balance, end of year	21,438,924	$ 5,558,614	17,738,937	$ 4,772,876

(i) During the year, the Company issued 3,499,987 Units priced at $0.45. Each unit consisted of one Common Share and one Purchase Warrant. Each Purchase Warrant entitles the holder to purchase on additional Common Share at an exercise price of $0.70 per Common Share until February 17, 2007. The warrants have been ascribed a fair value of $700,000 using the Black-Scholes pricing model assuming a risk-free interest of 3 percent; weighted average life of 1.5 years; dividend yield of nil; and expected volatility rate of 121 percent. Sinalta Investments Ltd. was paid a finder's fee of $100,000, and granted warrants to 500,000 Common Shares at an exercise price of $0.70 until February 17, 2007. These warrants have been recorded as share issue costs estimated at $120,000 using the Black-Scholes pricing model assuming a risk-free interest rate of 3 percent; weighted average life of 1.5 years; dividend yield of nil; and expected volatility rate of 121 percent. All shares are subject to a hold period to January 17, 2006.

(ii) The increase in share capital as a result of the exercise of stock options is comprised of the amount of cash received of $79,000 and the compensation expensed previously of $22,060.

b) Warrants

	Weighted Average Exercise Price	Number	Amount
Balance, beginning of year	$ -	-	$ -
Private placement agent warrants (note 5 (a)(i))	0.70	500,000	120,000
Unit private placement (note 5(a)(i))	0.70	3,499,987	700,000
Balance, end of year	$ 0.70	3,999,987	$ 820,000

c) Contributed surplus

	2005	2004
Balance, beginning of year	$ 380,060	$ 94,111
Compensation recognized in the year	176,308	300,649
Adjustment for options exercised in the period	(22,060)	(14,700)
Balance, end of year	$ 534,308	$ 380,060

d) Per share amounts

Earnings (loss) per common share are calculated using the weighted average number of common shares outstanding during the year. A reconciliation of the denominators used in the per share calculation is outlined below:

	2005	2004
Basic beginning of period	18,994,641	17,738,937
Effect of dilutive options and warrants	2,752,516	-
Diluted weighted average common shares	21,747,157	17,738,937

6. Stock based compensation

The Company has a stock option plan for directors, officers and key employees. The exercise price of each option equals the market price of the Company's stock on the date of grant. Options vest after one year and expire after a maximum period of five years from the date of issue.

In 2004, the Company changed the vesting period for all outstanding stock options to be one year from issuance of the option, from previously being vested equally over three years. As a result of the change to the stock option plan, compensation costs for the year ended December 31, 2004 increased by $174,734.

A summary of the status of the company's stock option plan as of December 31, 2005 and 2004 and changes during the year are presented below:

	2005		2004	
	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
Balance beginning of year	1,510,000	$ 0.49	1,310,000	$ 0.42
Granted	810,000	0.50	350,000	0.70
Exercised	(200,000)	(0.40)	(50,000)	(0.30)
Expired	-	-	(100,000)	(0.42)
Balance end of year	2,120,000	$ 0.50	1,510,000	$ 0.49
Exercisable end of year	1,310,000	$ 0.50	1,160,000	$ 0.43

The following table summarizes information about stock options outstanding at December 31, 2005:

	Options Outstanding			Options Exercisable	
Exercise Price	Number Outstanding	Weighted Average Remaining Contractual Life		Number Exercisable	Weighted Average Remaining Contractual Life
$ 0.30	10,000	2.04		10,000	2.04
0.42	700,000	2.52		700,000	2.52
0.49	250,000	0.60		250,000	0.60
0.50	800,000	4.54		-	-
0.52	10,000	4.65		-	-
0.70	300,000	3.45		300,000	3.46
0.71	50,000	3.22		50,000	3.22
	2,120,000	3.19		1,310,000	2.40

Compensation cost of $176,308 (2004 - $300,649) has been recognized for stock options granted during the year.

The weighted average fair value of each option granted during the year ended December 31, 2005 is estimated on the date of grant using the Black-Scholes options pricing model with the following weighted average assumptions:

	2005	2004
Fair value of options granted ($/share)	$ 0.33	$ 0.60
Risk-free interest rate (%)	3.40	4.24
Expected life (years)	3	3
Expected volatility (%)	102	133
Expected dividend yield (%)	-	-

7. Income taxes

The following table summarizes the temporary differences, which give rise to the future income tax liability at December 31:

	2005	2004
Future income tax liabilities		
Property, plant and equipment	$ 577,232	$ 393,023
Future income tax assets		
Asset retirement obligation	(73,263)	(54,599)
Share issue costs	(77,142)	-
Balance, end of year	$ 426,827	$ 338,424

At December 31, 2005, the company has successor tax pools of approximately $365,399 (2004 - $365,399) available for deduction from future taxable income. These successor pools have not been recognized for purposes of the future tax calculation due to the uncertainty as to whether sufficient revenue will be realized from the related properties to utilize the pools.

The income tax provision differs from the amount computed by applying the expected income tax rate of 37.62 percent (2004 – 38.87 percent) to earnings before taxes. The reasons for this difference are as follows:

	2005	2004
Earnings (loss) before taxes	$ 433,617	$ (733,087)
Expected tax rate	37.62%	38.87%
Expected tax expense at combined federal and provincial rates	$ 163,127	$ (284,951)
Crown royalties and production taxes	149,550	89,076
Alberta royalty tax credit	(57,519)	(29,692)
Resource allowance	(128,209)	(95,826)
Stock based compensation	66,327	116,862
Decrease in future taxes due to tax rate reduction	(3,396)	-
Other	(4,977)	13,531
Balance, end of year	$ 184,903	$ (191,000)

8. Commitments

The present office lease agreement expires on September 30, 2006. Future lease payments to the end of the lease term under the company's office lease will total $31,531 plus operating costs.

9. Financial instruments

Fair value

Financial instruments include bank indebtedness, accounts receivable, and accounts payable and accrued charges. At December 31, 2005, the fair market value of the financial instruments approximated their carrying value due to the short-term maturity of these instruments.

Credit risk

Substantially all of the Company's accounts receivable are due from customers in the oil and gas industry and are subject to normal industry credit risks.

Interest rate risk

The Company is exposed to interest rate cash flow risk to the extent that its bank loans are at a floating rated on interest. The related disclosure regarding these debt instruments is included in note 3 of these financial statements.

10. Related party transactions

During the year, the Company purchased engineering services in the amount of $369,663 (2004- $365,484) from a director of the Company and professional services in the amount of $26,636 (2004 - $16,946) from an officer of the Company. These transactions were recorded at the exchange value which represents the agreed upon price between the two transacting parties. Included in accounts payable at December 31, 2005 is $177,822 (2004 - $30,296), payable to related parties.

11. Cash flows – supplemental information

	2005	2004
Changes in non-cash working capital		
Operating Activities:		
Accounts receivable	$(470,221)	$(516,829)
Prepaid deposits	(5,120)	905
Accounts payable and accrued charges	674,178	1,026,076
	198,837	510,152
Investing Activities:		
Accounts receivable	161,840	(324,339)
Accounts payable and accrued charges	48,470	391,171
	210,310	66,832
	$409,147	$576,984